Idaho Power Company's Comments
September 2, 2016
RE: NARUC Draft Manual on Distributed Energy Resources Compensation

Idaho Power Company ("Idaho Power") appreciates the opportunity to provide comments on NARUCs' *Draft Manual on Distributed Energy Resources Compensation* ("Manual"). Idaho Power has also had an opportunity to review the comments submitted by the Edison Electric Institute ("EEI") (of which, Idaho Power is a member) and Idaho Power supports EEI's position on the issues addressed in its comments.

Idaho Power Company:

Idaho Power is a fully integrated, investor-owned electric utility with service areas covering southern Idaho and eastern Oregon. Idaho Power serves approximately 525,000 customers across both jurisdictions. Idaho Power has approximately 440,000 residential, 65,000 commercial and industrial, and 20,000 irrigation customers. Idaho Power's tariff provides for traditional net metering[1] and Idaho Power has approximately 1,000 customers taking service under its net metering schedule.[2]

Comments:

Idaho Power appreciates NARUC and the NARUC Subcommittee on Rate Design taking the time and effort to investigate a holistic look at the important issues around rate redesign and utility cost recovery associated with the growing deployment of distributed energy resources ("DER"). Idaho Power also appreciates the opportunity to provide comments that will be considered as the final draft of the Manual is compiled. In light of that, Idaho Power's comments are narrowly focused on three areas: (1) the time to address rate design and cost recovery issues for customers with DER is now, (2) rate design must reflect fair utility cost

[1] Customers are able to net consumption from generation on a monthly basis, with consumed generation credited at the full retail rate. Any excess net energy in a billing period is carried forward, indefinitely, as an on-bill 'kWh' credit available to offset future consumption.

[2] IPUC No. 29, Tariff No. 101, Schedule 84 CUSTOMER ENERGY PRODUCTION NET METERING https://www.idahopower.com/AboutUs/RatesRegulatory/Tariffs/tariffPDF.cfm?id=198

recovery from all customers who utilize the grid, and (3) customers who install DER are fundamentally and uniquely different from standard service customers.

Idaho Power has experienced significant growth in its net metering service over the last several years, and has recently quantified that some cost shifting is already occurring from its residential net metering customers to the remaining residential customers who do not participate in net metering. In an April 2016 compliance report filed with the Idaho Public Utilities Commission,[3] Idaho Power estimates that, assuming a median growth rate, the potential for future annual cost shift by 2021 could be $1.3 million, with a low and high growth rate scenario ranging from $775,000 to as much as $1.9 million, respectively.

I. The Time to Address Rate Design and Utility Cost Recovery Issues for Customers with Distributed Energy Resources is Now.

As utilities like Idaho Power continue to experience rapid growth in the adoption of customer self-generation, it is critically important for the regulatory paradigm to keep pace. The way that customers want to take service from their utility is changing. Commissions across the country are well positioned to address these issues, and must not wait for higher penetrations in their particular jurisdictions as currently suggested in the Manual.[4] The time to address rate design for customers with distributed energy resources is now. Under high penetration conditions, as has happened in states like Arizona, Hawaii, and California, regulators are not just dealing with the challenges of a rate redesign, but also with the existing problems of substantial cost shifting, increased customer confusion and dissatisfaction,[5] and how existing customers will be impacted by any rate design changes.

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[3] http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1227/company/20160429ANNUAL%20NET%20METERING%20REPORT.PDF

[4] *Draft NARUC Manual on Distributed Energy Resources Compensation*, July 2016.

[5] *See* Energy+Environmental Economics (E3), *Nevada Net Energy Metering Impacts Evaluation* (July 2014), http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf; *see also,* E3, *Updated Nevada Net Energy Metering Impacts Evaluation* (Aug. 2016), p. 16. http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-8/14179.pdf. *See*

Idaho Power appreciates that the Manual is clear in its recognition of the well documented issues surrounding the cost shift associated with the status quo of net energy metering ("NEM"). NEM is non-cost based, and is reflective of a time when utilities, and utility rate designs, were limited to using meters that could only track inflow and outflow, and DER was an expensive fledgling technology. Fast forward to today, and the situation has changed. Idaho Power and many other utilities have deployed advanced metering infrastructure that can enable more precise, accurate, and equitable rate designs that were not possible for most utilities a decade ago.

In addition to recognizing the potential cost shift, the Manual should also take notice of some of the challenges that state commissions have gone through when addressing DER at higher levels of penetration. In particular, the substantial increase that has been seen in customer confusion about changing rate designs, which can have a negative impact on previous investments they have made in their DER systems and can result in higher customer dissatisfaction from both DER and non-DER customers alike. This customer dissatisfaction has been a significant driver in high profile contentious proceedings that have played out across the high penetration states of California, Hawaii, Nevada, and currently Arizona.[6] Addressing the rate redesign as early in the process as possible, coupled with increased customer education from DER providers and utilities alike, will provide increased certainty for a greater number of customers as they consider investments and will likely lead to increased customers satisfaction.

Finally, in June of this year, the President's Council of Economic Advisors issued a report on incorporating both renewables and DER technologies into the power grid highlighting the need for states to refine rate structures across the country in a timely manner.[7] The report concluded

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also, E3, *California Net Metering Ratepayer Impacts Evaluation* (Oct. 28, 2013), http://www.cpuc.ca.gov/General.aspx?id=8919.

[6] The Nevada Commission in addressing this dissatisfaction stated that "[t]he lack of customer acceptance was compounded by the complete lack of information provided by the small-scale (rooftop) solar vendors (except Bombard) to potential solar customers that NEM rates may change pursuant to SB 374." Nevada Order, p. 116.

[7] Executive Office of the President, Council of Economic Advisors, *Incorporating Renewables into the Electric Grid: Expanding Opportunities for Smart Markets and Energy Storage* (June 6, 2016) (CEA Report), p. 34, https://www.whitehouse.gov/sites/default/files/page/files/20160616_cea_renewables_electricgrid.pdf.

that the realization of the potential benefits of DER requires new approaches to the pricing for electricity to create a "level playing field" that allows all DER to participate.[8] The report also stressed that delay and uncertainty are bad for both innovation and technology development.[9]

In order to facilitate the continued growth and development of distributed generation technologies in a fair and sustainable manner, Idaho Power believes the time to address the important issues around utility rate design is now.

II. Rate design must reflect fair cost recovery from all customers who utilize the grid.

Updating rate designs is critical because legacy rate designs expose customers to increasing potential cost-shifts as the penetration of new technologies, such as DER, grows. For a variety of reasons, including metering limitations and policy considerations, residential retail rates historically have been designed to recover the overwhelming majority of the total costs of service, primarily driven by infrastructure needs, on the basis of energy consumption, with typically over half of the fixed costs and capacity-related costs included in the volumetric kilowatt-hour ("kWh") charge. Idaho Power's residential rate design is comprised of a $5.00 monthly fixed service charge coupled with tiered volumetric kWh rates that recover from customers the remainder of the fixed capacity-related costs and all of the energy-related costs. Idaho Power's average residential customer bill would be comprised of approximately 5 percent reflecting the fixed service charge with the remaining 95 percent of the bill being collected through the volumetric kWh charge. However, Idaho Power's residential class' revenue requirement is comprised of approximately 67 percent fixed capacity and customer-related costs and 33 percent energy-related costs. Idaho Power believes that implementing rate designs that reduce the reliance on volumetric kWh charges for recovering fixed costs are needed to ensure that fixed infrastructure costs are equitably shared across all customers that use and rely on the grid.

[8] *Id.*

[9] *Id.*

In order to provide electricity to customers, Idaho Power has to make investments, directly or indirectly, in infrastructure related to generation, transmission, distribution, metering, and customer service (such as billing and customer inquiry systems). Generation costs consist of both the cost for capacity and the cost for energy. Capacity investments tend to be "lumpy," cost intensive, and have long asset lives and capital payback structures. Energy costs, which for purposes of this discussion are not considered infrastructure costs, are generally a function of electricity consumption and fuel costs, and will vary from hour-to-hour depending on available generation resources. Distribution and transmission costs are also generally allocated as a function of peak demand — the system must be built to meet maximum system and non-coincident demand in order to provide service and maintain reliability. Distribution networks, and some transmission networks, are generally sized to meet peak demand at the locational level while the transmission system and generation capacity are sized to meet system peak demand. The costs for metering and customer services vary with the number and type of customers and are considered a fixed cost for each customer, but may also vary across time.

The fundamental regulatory principle of assigning costs to cost causers is ever more important as customers have new opportunities to self-generate and potentially store electricity. When rate structures are not reflective of the cost structure, customers receive flawed price signals that may lead them to behave in inefficient and costly ways with regard to their energy decisions, which may result in a misallocation of resources. The most straightforward approach to cost-based rate design for distribution or grid services is to support a rate design reflecting cost causation by properly aligning the fixed and variable price signals sent by delivery rates with the fixed and variable costs imposed by customers' demand of the delivery system.

Today's fixed charges are far below the utility's cost of providing grid services, which, as previously discussed, includes transmission, distribution, generation capacity, and ancillary and balancing services. Idaho Power believes that educating customers about what they are paying for when they purchase electricity — both grid services and energy — is critically important. Yet, the public does not understand this distinction because we — utilities, regulators, and other stakeholders — have implemented electricity pricing that is not reflective of cost causation.

Idaho Power believes that net metering policies need to be revised so that customers with DER are credited appropriately for the potential value to the grid created by the products that they supply. However, regulators should be cautious about providing a "value" to customers in addition to the current subsidy that exists within existing rate designs. If a "value-based" methodology is to be considered in the Manual, it is important to remember that in a regulated environment, rates for utility infrastructure investment are established to recover costs from customers, not to provide value for benefits that are external to the utility's costs.

More specifically, the value of DER discussion often includes an assessment of these externalities, like emission reductions as estimated by the social cost of carbon, or macro-economic development or job impacts, when defining the benefits of a particular resource to the grid. However, this approach is never applied holistically to attribute the same kinds of benefits to other energy resources that provide identical benefits in terms of clean energy, jobs, etc., and thus tends to result in a distorted pricing system that is biased in favor of one resource to the detriment of competitive sources of power that can provide the same benefits, often at lower costs.

Idaho Power believes the following criteria should be utilized in determining the value of benefits to be included in a "value-based" DER compensation mechanism, in order for non-participant customers to be held harmless:

- Benefits should be capable of being monetized by utility.
- Benefits should offset items that would otherwise be included as a recoverable cost in a utility's revenue requirement.
- Benefits should be cost-effective in comparison to alternative utility options.

III. Customers Who Install DER are Fundamentally and Uniquely Different from Standard Service Customers

The Manual appropriately points out that in many instances, it is appropriate to consider creating a separate DER rate class as growth in DER and future adoption of new DER technologies are changing the characteristics of customer electricity supply and service requirements for electric utilities. DER customers may self-supply all, or a portion, of their electricity requirements, while potentially offering valuable services to the grid. This makes them unlike other customers who rely on the utility for their entire electricity requirement. Retail electricity rates for commercial and industrial customers are typically designed differently than rates for residential customers, typically with energy and demand elements, so as to better address both the customers' needs and their use of the grid. Separate rate classes for residential customers with DER are an option that some state commissions may explore as they move forward in addressing DER compensation. Separate rate classes for different types of customers have long been a tool that public utility commissions use to try to balance the equities among different kinds of energy consumers.

Separate rate classes should be considered for several important reasons. First, there are likely significant differences in customer load characteristics and cost-of-service between full requirements service customers and partial requirements service customers that are not reflected under current rate structures. Second, separate tariff schedules for partial requirements service customers should be required for customers who choose to change the manner in which they use the grid and receive electric service by installing DER. Third, separate tariff schedules for partial requirements service customers do not affect full requirements service customers and avoid the regulatory challenge of establishing demand charges and other tariff modifications for non-DER customers. Fourth, a separate tariff offering could be designed to provide appropriate price signals to incentivize and reward DER technologies for the benefits they may provide to the grid. Fifth, a separate tariff schedule could more easily be adjusted as the economic value of grid capacity deferral changes due to increased DER penetration, without significantly affecting the rate or tariff structures of non-DER customers. Finally, separate tariff schedules can provide transparent price signals for DER technologies without impacting schedules applicable to non-DER customers.

The Manual cites the *1992 NARUC Electric Utility Cost Allocation Manual* ("1992 Manual") stating "customers are separated into classes based on some important distinction in the service provided to different groups of customers which affects the cost to serve those customers."[10] As

[10] Manual, p. 29.

noted in the 1992 Manual, "customers served by the utility are separated into several groups based on the ***nature of the service provided*** and load characteristics."[11] Emphasis added. Idaho Power believes that customer segmentation should not merely be a function of segmenting customers with unique cost patterns, but rather a recognition that either the nature of service and/or unique customer load profiles may require a different customer class.

IV. Conclusion

Idaho Power would like to thank NARUC for taking on this incredibly useful task, and appreciates the opportunity to comment on the Manual. Given the ever evolving nature of technology, particularly those that are the subject of this document, periodic updates to this Manual may be needed. Idaho Power respectfully suggests that as more information is learned through experience, the Manual should be updated accordingly.

[11] NARUC Electric Utility Cost Allocation Manual, 1992, p. 22.